Summary Table of V.2.1.6 Updates

ID	Feature	Description	Doc. Report Section[1]
Power System Operations Assumptions			
1	Revised aggregation scheme ("Documentation for v.2.1" refers to the report *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model*, EPA 430/R-02-004 (March 2002), which is available for viewing and downloading at www.epa.gov/airmarkets/epa-ipm.	The aggregation scheme was revised to enable modeling emission scenarios in geographical areas most likely to be of future interest. Table A-1 in Attachment A updates the crosswalk between actual and model plants that was previously presented as Table 4.7 in the documentation for v.2.1. Table A-2 and the accompanying map provides details on the geographical aggregation scheme used in the v.2.1.6.	3.1 4.2.6 Appendix A4.1
2	Electricity Demand Growth: @ 1.55% indexed on AEO 2003 electricity sales projections. (AEO 2003 refers to *Annual Energy Outlook 2003 with Projections to 2025,* DOE/EIA-0383(2003), released by the U.S. Department of Energy's Energy Information Administration on January 9, 2003.)	1. As was done in EPA's previous applications of IPM, calculations were performed to account for efficiency improvements not factored into AEO 2003's projections of electricity sales. This resulted in a 2000-2020 adjusted electricity growth rate of 1.55% per year. Attachment B provides details.	3.2.1 3.2.2 Appendix A3.1
3	State Multi-Pollutant Regulations	Attachment C lists the state multipollutant programs incorporated in v.2.1.6.	3.9
4	New Source Review (NSR) Settlements	Attachment D shows the settlements under New Source Review provisions of the Clean Air Act that were included in v. 2.1.6.	3.9.3
5	State Renewable Energy Programs	V. 2.1.6 incorporates the capacity shown in Table 76 in the AEO 2003 assumptions document. Entitled "Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources," the table captures the effects of state renewable energy programs in its projection of both existing and forecasted renewable capacity. Table 76 appears on pp. 131-133 of the document "Assumptions for the Annual Energy Outlook 2003," which can be found on the Web at www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf.	3.9.4 (Not covered)
6	State Renewable Portfolio Standards (RPS)	V. 2.1.6 does not endogenously model RPS beyond the capacity already implicit in Table 76 "Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources." (See previous item for information on locating this table.)	3.9.4 (Not covered)

ID	Feature	Description	Doc. Report Section[1]
7	Emission and removal rate assumptions for potential units.	The emission and removal rates are the same as in AEO 2003, i.e., NOx Rates / SO2 Rates Conventional Pulverized Coal (CPC): 0.11 lb/mmBtu, 95% Removal Integrated Gasification Combined Cycle (IGCC): 0.02 lb/mmBtu, 99% Removal Combined Cycle (CC): 0.02 lb/mmBtu, — Combustion Turbine (CT): 0.08 lb/mmBtu, — These differ from the removal rates in v. 2.1 (also called EPA Base Case 2000). See Attachment E for a detailed breakdown of the differences.	3.9.5
Generating Resources			
8	National Electric Energy Data System (NEEDS) Changes		4.1 4.2
	The following changes were made to NEEDS, the database that serves as the source of all currently operating and planned/committed units represented in v.2.1.6.		
8a	AES Deepwater Unit	The AES Deepwater generating unit in Texas (ID #10670_G_GEN1) was identified as combusting fossil waste in NEEDS 2000 (used for the EPA Base Case 2000, v2.1) but as combusting oil in EPA's Emissions and Generation Resource Integrated Database (EGRID). Further investigation revealed that this unit burned petroleum coke and some oil. To give a more accurate representation of its mercury emissions, in v. 2.1.6 the unit was designated as combusting petroleum coke and assigned a corresponding mercury emission rate of 23.18 lb/TBtu (dry).	
8b	Mercury Emission Rates for Existing Geothermal Units	Based on recent information obtained by EPA, mercury emission rates were updated to 2.97 lbs/TBtu for existing geothermal units in California and 3.65 lbs/TBtu for existing geothermal units in the IPM model region NWPE. In addition, 29 MW of existing geothermal capacity was identified in the AZNM model region and 8 MW in the PNW model region and assigned an emission rate of 3.70 lbs/TBtu, the same emission rate as assigned to new potential geothermal units in v.2.1.6. (See item #10 below.)	
8c	Hawthorn Unit 5	This 550 MW coal unit was added to NEEDS, v. 2.1.6.	
8d	Updated information on unit closures	Units that were shown as retired or out of service in 2000 EIA 860a were removed from the NEEDS database as part of the v.2.1.6 update. Based on supplemental information, Ashtabula units 8, 10 and 11, Arapahoe units 1 and 2, Arkwright units 1 - 4, 5A, 5B,and Mitchell units 1 and 2 were also removed from the NEEDS population, either because they were retired or out of service.	4.2

ID	Feature	Description	Doc. Report Section[1]
8e	Life Extension Costs	A life extension cost of $5/kW-yr is added to every fossil plant that reaches an age of 30 years. This assumption is based on AEO 2003.	4.2.4 and 4.3.4
8f	SO_2, NO_x, and Particulate Controls	The inventory of SO_2, NO_x, and particulate controls in v.2.1.6 was derived from U.S. EPA's Emission Tracking System, 2002, Quarter 2, supplemented by corroborated information obtained from utilities, control technology vendors, state and regional regulatory agencies, and trade publications and announcements. Attachment F shows the inventory of emission controls on existing generating units that are included in v.2.1.6.	4.2.5
8g	Updated planned/committed capacity	Existing and planned/committed units in NEEDS 2.1.6 were derived from the following data sources: <u>Period</u> — <u>Source</u> 1998 and earlier — NEEDS 2000 All planned/committed capacity after 1998 in NEEDS 2000 was removed and replaced with the following data. 1999-2000 — EIA 860, as released in year 2000. EIA 860 shows operating units for these years. 2001 — RDI. (Updated through the July 2002 release of the RDI database.) 2002-2005 — AEO 2003 or RDI. AEO 2003 was used for renewable (biomass, geothermal, landfill gas, hydro, pumped storage, solar, and wind) and non-conventional generating units (fuel cells) due to the Energy Information Administration's (EIA) extensive research in this area for AEO 2003. The RDI database (up through the July 2002 release) was used for conventional generating units (coal steam, combined cycle turbines, combustion turbines, fossil and non-fossil waste) since it was more current than AEO 2003. Attachment G lists the planned/committed units included in NEEDS 2.1.6 and gives a detailed summary of the data sources used.	4.3
9	Cost and Performance of Potential	The cost and performance assumptions for new (potential) conventional pulverized	4.4.2

ID	Feature	Description	Doc. Report Section[1]
	(New) Capacity from Conventional Generating Units	coal, integrated gasification combined cycle, combined cycle, advanced combined cycle, and combustion turbine units were updated based on AEO 2003. See Attachment H for details.	
10	Mercury emissions for new (potential) geothermal units	Based on recent information obtained by EPA, the mercury emission rate for new (potential) geothermal plants was updated to 3.70 lbs/TBtu in v.2.1.6, compared to 4.08 lbs/TBtu in v.2.1. (See item 8b above for a description of related updates of the mercury emission rates for existing geothermal plants.)	4.4.3 5.3.1
11	Existing Nuclear Units		
11a	Cost and performance	1. To provide maximum granularity in forecasting the behavior of nuclear units, 102 out of the 103 existing nuclear units in v.2.1.6 are represented by separate model plants. (Note: All nuclear generating units, except Browns Ferry units 1 and 2 are represented by a separate model plant. In the v.2.1.6 base case, Browns Ferry Unit 1, which is projected to be brought out of mothballs, is represented by the same model plant as Browns Ferry Unit 2. See item 11c below for further details.) In v.2.1, the 103 existing nuclear units were represented by 47 model plants. 2. AEO 2003 cost and performance assumptions were implemented. These include (a) Variable operations and maintenance (VOM), fixed operations and maintenance (FOM), and fuel cost assumptions as in AEO 2003. Attachment I details the cost assumptions included in v. 2.1.6. (b) AEO 2003 assumption of cost incurred from age 30, i.e., an addition of $50/Kw/yr to annual FOM costs starting at age 30. (c) Availability assumptions are expressed in terms of capacity factors, which are based on AEO 2003. As in AEO 2003, v. 2.1.6 assumes two vintages of existing nuclear units, based on whether a unit's start date occurs before or after 1982. For the older vintage, the capacity factor increases 0.5 percentage point per year through age 25, stays flat from 25-40, and then declines by 0.5% point after 40. The capacity factor of a newer vintage unit increases by 0.7 percentage point per year through age 30, is flat from 30-40, and declines by 0.5% point after age 40. The maximum capacity factor is assumed to be 90%. Any plant starting with a capacity factor above 90% just remains at its current level, at least until it is old enough to start declining. 3. In v.2.1.6 existing nuclear units are constrained to retain the same retirement pattern as in AEO 2003.	4.5 Appendix 4.4

ID	Feature	Description	Doc. Report Section[1]
11b	Upratings	All the nuclear capacity uprating assumptions that are in AEO 2003 were incorporated in NEEDS 2.1.6. A listing of all upratings appears in Attachment J.	4.5 Appendix 4.4
11c	Browns Ferry Unit 1	V. 2.1.6 uses the same assumptions about this TVA unit being brought out of mothballs as in AEO 2003, i.e., 1. The unit has a zero capacity factor (availability) until 2007. Starting in 2007, it can operate up to a 75% capacity factor. 2. Like other existing nuclear units its capacity factor grows by 0.7% per year until it reaches a maximum of 90%. 3. Its costs were assumed to be the same as those for Browns Ferry Unit 2.	4.5 Appendix 4.4
Emission Control Technologies			
12	Selective Non-Catalytic Reduction (SNCR) Control of NOx Emissions	In v. 2.1.6 SNCR is available as an emission control retrofit option for all coal plants $25 MW and < 200 MW rather than to all plants $ 25, as in v.2.1. In both v.2.1 and v.2.1.6 SNCR is available to all oil/gas steam units $ 25 MW.	5.2.2
13	Gas Reburn Option for NOx Control at coal fired plants	To reduce model size, this option, which was provided in v 2.1, was not offered in v2.1.6.	5.2.2
14	Mercury Emission Modification Factors (EMFs)	Mercury emission modification factors are multipliers that represent the extent of mercury removal achieved by various configurations of NO_X, SO_2 and particulate emission controls at coal fired generating units. Based on additional information received on the performance of these controls, mercury EMFs were updated. Attachment K shows the mercury EMFs used in v. 2.1.6.	5.3.2 5.3.3 Appendix A5.4
15	Mercury Control Using Activated Carbon Injection (ACI)	Instead of modeling ACI with an 80% mercury removal rate, as was done in v. 2.1, v.2.1.6 has the capability to provide two concurrent ACI options of 60% and 90% mercury removal. The two options could be used for special mercury analyses. However, v. 2.1.6 will use an ACI mercury removal rate of 90% for typical analyses. Due to constraints on model size and run time, the 60% removal option is intended to be applied only on selected sensitivity analysis runs.	5.3.3 Appendix A5.3
16	Mercury Control Costs Using ACI	Based on information received from ACI vendors as an outgrowth of the Mercury MACT FACA process, the cost and injection rates for ACI were revised. ("Mercury MACT FACA process" refers to the advisory committee set up under the Federal Advisory Committee Act (FACA) to enable EPA to obtain input on proposed regulations governing maximum achievable control technology (MACT) for	Appendix A5.3.2

ID	Feature	Description	Doc. Report Section[1]
		mercury removal from electric generating units.) (See Attachments L1 and L2 for a complete development of the ACI cost equations used in v. 2.1.6.)	
Financial assumptions			
17	Revised financial assumptions for Integrated Gasification Combined Cycle (IGCCs) plants.	With the following exceptions, the financial assumptions in v.2.1.6 are the same as in EPA Base Case 2000 (v.2.1): IGCCs and Repowerings-to-IGCCs are assigned the discount rate (DR) and capital charge rate (CCR) associated with high (rather than medium) risk investments, i.e., DR = 6.74%, not 6.14%. CCR = 13.4%, not 12.9%	7
Fuel Assumptions			
18	Coal Supply Curves	To provide greater consistency between the v.2.1.6 and the AEO 2003 coal supply curves, the regional coal supply curves in v.2.1.6 were adjusted to reflect the percentage change in labor productivity assumed in AEO 2003. The coal transportation cost escalation rates in v.2.1.6 were also made consistent with those assumed in AEO 2003. See Attachment M for a presentation of the AEO 2003 labor productivity and transportation escalator assumptions.	8.1
19	Natural Gas Supply Curves	Updated gas supply curves were generated using ICF Consulting Inc.'s North American Natural Gas Analysis System (NANGAS) model. Key activities included: 1. Gas supply curves were developed for the 2005-2025, modeling horizon, rather than the 2005-2020 period used earlier. 2. Earlier optimistic technology assumptions, developed for the Department of Energy's National Energy Technology Laboratory's (NETL), were reviewed and revised resulting in a somewhat less optimistic technology perspective. 3. The Gulf of Mexico East drilling moratorium was incorporated in NANGAS. 4. EIA success rates for Gulf of Mexico offshore were adopted. 5. Pipeline links were checked to ensure correct gas flow, e.g., making sure the Rockies-Southwest link shows gas flows from the Rockies to the Southwest rather than the reverse. 6. Seasonal transportation adders were updated. 7. Four initial NANGAS runs were performed to cover the range of anticipated electric demand growth rates. A separate NANGAS run was performed at electric demand annual growth rates of 1.1%, 1.55% (EPA's CCAP adjusted growth rate),	8.2 Appendix 8.1

ID	Feature	Description	Doc. Report Section[1]
		1.88% (approximating the AEO 2003 Reference Case electricity sales growth rate), and 2.2%. 8. Outputs from the four runs were used to produce an initial set of natural gas supply curves for incorporation in IPM. 9. A series of iterations was performed between NANGAS and IPM until convergence was achieved in the IPM and NANGAS electric sector results. The gas supply curves generated by this process were incorporated in v.2.1.6. Attachments N contains the natural gas supply curves used in v. 2.1.6 for each model run year and the seasonal transportation adders.	
20	Oil prices consistent with AEO 2003	1. V. 2.1.6 fuel prices for distillate oil and high and low sulfur residual oil were based on the AEO 2003. The prices used in v.2.1.6 are shown in Attachment O together with the AEO 2003 source data from which the prices were derived. 2. The sulfur content for these fuels were defined to be consistent with AEO 2003, i.e., Fuel — Sulfur Content Distillate — 0.3 Residual: Low Sulfur — 1.08 Residual: High Sulfur — 2.69	8.3
Miscellaneous Other Features			
21	SO_2 allowance bank	An SO2 allowance bank of 6.414 million tons (going into 2005) was assumed.	
22	Feasibility constraint on the maximum amount of SO_2 scrubbers that can be built in 2005 under the v.2.1.6 Clear Skies run	The maximum amount of SO_2 scrubbers that could be built in 2005 was limited to 5066 MW in the Clear Skies run. This is consistent with recent EPA assessments of the short-term feasibility of scrubber installations.	

Notes

1.This column indicates the most closely related sections in *Documentation of EPA Modeling Applications (V. 2.1) Using the Integrated Planning Model* (EPA 430/R-02-004), March 2002. This report, which documents the assumptions underlying EPA Base Case 2000, can be viewed and downloaded from www.epa.gov/airmarkets/epa-ipm. The features listed in this table superceded corresponding assumptions in the documentation report.